Regarding Dynegy's request for clarification, we will not permit start-up fuel costs to be recovered under the refund methodology. It will be impossible to reconstruct and demonstrate what gas costs were incurred strictly for start-up that are not otherwise recoverable. For example, a unit may have incurred start-up costs in order to be available to provide spinning reserves (which is a capacity Ancillary Service). In this instance, it would be inappropriate to seek double recovery of those costs. Moreover, these start-up costs were allowed to be recovered in the June 19 Order because of the impact of the must-offer requirement, and that requirement was not in place during the refund period.

Dynegy and Mirant's objection to our requiring submission of an entire portfolio of units for cost-of-service rates is without merit. As a matter of policy and in an effort to avoid the gaming inherent in hybrid markets,[245] we will require that the entire portfolio choose to be under cost-of-service or under market-based rates.

We are also not persuaded by AEPCO's objection to the potential administrative burden for a cooperative to prepare cost-of-service justification. The City of Vernon, California provides an example of doing so without substantial difficulty.[246]

g. Treatment of Ancillary Services

The ISO argues on rehearing of the June 19 Order that the Ancillary Services price mitigation, as adopted, will result in Ancillary Services prices above just and reasonable rates and seeks to prohibit sellers from seeking or obtaining payments for Ancillary Services capacity bids above the applicable Market Clearing Prices. The ISO contends that an ex ante approach to Ancillary Services price mitigation is superior and that Ancillary Services price mitigation measures should be applied in all hours as of May 29, 2001, the effective date of the April 26 Order. PG&E contends that the Commission should distinguish between capacity and energy in Ancillary Services pricing, since capacity does not incur variable costs.

PG&E repeats this argument in the context of the refund methodology. As the July 25 Order did not address Ancillary Services pricing, PG&E seeks clarification that for capacity bids prior to June 20, 2001, gas prices and O&M charges should be subtracted from the hourly Ancillary Services market clearing price. Similarly, the ISO

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[245]See, e.g., AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998), order on rehg 87 FERC ¶ 61,208, order on further reh'g, 88 FERC ¶ 61,096 (1999), order on further reh'g, 90 FERC ¶ 61,036 (2000).

[246]See City of Vernon, California, 93 FERC ¶ 61,103 (2000), reh'g denied, 94 FERC ¶ 61,148 (2001).

and California Parties note that sellers who provide energy pursuant to a capacity bid under the ISO Tariff would be paid twice for expenses such as gas, start-up fuel and O&M, and argue that on rehearing the Commission should direct that the mitigated price for replacement reserves and Ancillary Services should not include these costs.

Enron and Reliant request clarification of the June 19 Order that the mitigated Market Clearing Prices be known at the time an Ancillary Service transaction is confirmed. They contend that the current mitigated Market Clearing Prices, which can change hourly and without notice, does not provide the certainty the Commission supports. They request clarification that the mitigated Market Clearing Prices in effect at the time the Ancillary Service deal is transacted, rather than the mitigated Market Clearing Prices in effect when delivery takes place, will apply to the transaction.

PG&E argues that the July 25 Order's refund methodology should also provide for refunds of the entirety of the amount spent on replacement reserves between October 2, 2000 and December 31, 2000. According to PG&E, the rationale for such refunds is essentially the same as that cited by the Commission for applying the refund methodology to spot market OOM transactions, that is, the replacement reserves were needed for the ISO to reliably operate the grid, and thus they should receive the same treatment. Because the ISO tariff allocated the entire cost of replacement reserves to the buyers that had failed to meet their demand in the PX markets, and sellers had not submitted bids in the auction with which buyers could service all their load, PG&E argues that the cost allocation effectively imposed an unwarranted penalty on buyers.

Commission Response

The Commission addressed issues of price mitigation for Ancillary Services in an order issued May 25, 2001, clarifying and providing preliminary guidance for implementing the April 26 Order.[247] The May 25 Clarification Order provided that the ISO should use the relevant hourly mitigated Imbalance Energy price to cap the other Ancillary Services markets. Thus:

> If the Ancillary Services markets clear below the average hourly mitigated Imbalance Energy price for that hour, then the ISO will pay the Ancillary Services clearing price for that market. If the Ancillary Services markets clear above the

[247] San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,275, reh'g denied, 96 FERC ¶ 61,051 (2001) (May 25 Clarification Order). On rehearing, the Commission indicated that the Ancillary Services issues should be raised on rehearing of the June 19 Order, so they are appropriately addressed in the instant order. See 96 FERC at 61,128.

> average hourly mitigated Imbalance Energy price, then the ISO will use that [Imbalance Energy] price to clear the market and will pay as-bid for all Ancillary Services that are needed above the mitigated price. Bids accepted above the mitigated price will be subject to refund and justification.

95 FERC at 61,971-72. It is in this context that the ISO and PG&E object to generators' ability to potentially justify Ancillary Services prices above the mitigated Market Clearing Prices.

The ISO Tariff provides that a supplier of capacity reserves will receive a capacity payment based on the market clearing price of the particular Ancillary Service in which its bid is accepted, and, if called upon to run, the supplier will also receive the Imbalance Enèrgy market clearing price for its energy. In the case of replacement reserves, a supplier receives only an energy payment if its capacity is called upon. Parties here want spinning and non-spinning reserves treated the same as replacement reserves. This would require a change in the tariff provisions that is outside the scope of this proceeding. Capacity payments have been intended as a contribution toward a supplier's fixed costs, whereas suppliers' marginal costs are covered by the energy payment. The issue whether to continue payments toward suppliers' fixed costs is not before the Commission in this proceeding.

The appropriate level of compensation for supplying capacity may differ from the appropriate energy prices, because fixed costs differ from marginal costs. For this reason, it would not be appropriate to subtract certain variable costs from the Ancillary Services market clearing price, as PG&E suggests. To the extent Ancillary Service markets clear below the hourly Imbalance Energy clearing price, no further adjustment is necessary. However, these markets will be limited to the Imbalance Energy clearing price in recognition that there is a relationship between offering the capacity in lieu of providing energy in real time. Prior efforts to decouple these markets resulted in insufficiency in the capacity markets.[248]

The ISO, Enron and Reliant seek some type of ex ante pricing. The ISO proposes that prices in the Ancillary Services capacity markets in all hours including system emergency hours be limited to 85 percent of the most recently established mitigated reserve deficiency MCP, asserting that such an approach is more consistent with the Commission's intention to set prices before they are charged. While Enron and Reliant

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[248]See AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998), order on rehg 87 FERC ¶ 61,208, order on further reh'g, 88 FERC ¶ 61,096 (1999), order on further reh'g, 90 FERC ¶ 61,036 (2000).

also seek a price that is known before the price is charged and that will not change, that price would not be capped. This topic is addressed in the order on the ISO's compliance filings that is being issued concurrently with this order. As we explain in that order, changes in the mitigated reserve deficiency MCP for the Imbalance Energy market should have no effect on prices in the Ancillary Services markets. Thus, we agree with Enron and Reliant that the price for the hour a transaction is entered into, and not the hour of delivery, is relevant for establishing the market clearing price for Ancillary Services. We will grant rehearing of our prior orders on this point, to the extent needed to allow this modification. We will not adopt the ISO's proposal because, as discussed above, the Ancillary Services markets should not be capped at a level lower than the Imbalance Energy market.

We do not agree with PG&E that replacement reserves costs should be refunded in their entirety. As explained above, prices in each of the ISO's auctions will be subject to refund to the extent they exceed the mitigated Market Clearing Prices in the Imbalance Energy market. To require the entire amount the ISO spent on replacement reserves to be refunded would be inconsistent with the treatment of the other Ancillary Services, and PG&E has not justified why replacement reserves should be treated differently. Even in a functional, competitive market, the ISO would have had some replacement reserves expenses. Replacement reserves are directly assigned to Imbalance Energy service and are needed for reliability purposes.[249] This is a necessary link that PG&E has not provided any explanation for breaking. Furthermore, PG&E's rationale with respect to OOM transactions is flawed. We did not order complete refunds for OOM transactions but are merely subjecting them to the same mitigation formula as other ISO transactions. To the extent that PG&E's problem may lie with cost allocation, we find that issue to be outside the scope of this proceeding.

Regarding the period between May 29 and June 20, 2001, the July 25 Order provided that the refund methodology would apply to non-reserve deficiency hours for those days. Rather than applying price mitigation to the Ancillary Services markets for all hours for that period, we clarify that the refund methodology and procedures will apply to the non-reserve deficiency hours.

3. Other Refund Issues

a. The July 25 Refund Methodology was Properly Applied to All Sales at Issue

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[249] See Amendment No. 33 Order, 93 FERC ¶ 61,239 (2000).

Many marketers and generators challenge the Commission's determination that prices charged were unjust and unreasonable. For example, EPSA and Williams argue that refunds are inappropriate because the Commission made no finding that any market participant exercised market power, never defined market power, and made no factual determination that warrants refunds in all hours. Others complain that the Commission made no findings that rates were unreasonably high or were increased above reasonable levels through market power.[250] Many assert that the Commission's findings violate section 206 of the FPA and the Administrative Procedure Act because there was no record evidence supporting those findings and because sellers were not afforded due process to address the issue on the record.[251] Williams and Reliant contend that the Commission erred by imposing refunds without substantial record evidence in support. As a result, these parties argue that imposing refunds violates the rule against retroactive ratemaking, the filed rate doctrine, and the Mobile Sierra doctrine.[252] In addition, they argue that the July 25 Order is contrary to long-standing precedent regarding retroactive rule changes and that the Commission erred in providing inadequate notice and explanation of changes in its policies.[253]

A number of parties argue that the filed rate doctrine forbids the Commission from ordering refunds with respect to transactions that were conducted in accordance with all Commission-approved rules (e.g., breakpoints, price caps or proxy prices) in effect at the time of the transactions.[254] They argue that the filed rate may be a formula rate and that a market-based rate is a formula rate, with the formula comprising the rules that govern the functioning of the market. With respect to the ISO and PX spot markets during the relevant periods, they argue that the rules that governed the functioning of the markets were the individual sellers' market-based rate authorizations, the Commission-approved ISO and PX tariffs, and the various Commission orders in effect at particular times. They argue that, if the Commission has never determined that an individual seller

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[250]See, e.g., Requests for Rehearing of Mirant, Nevada IEC/CC Washington, PSNM, Dynegy, Duke.

[251]See, e.g., Requests for Rehearing of Williams, Mirant, Nevada IEC/CC Washington, Marketer Group.

[252]See, e.g., Requests for Rehearing of BP, Duke, EPSA, Marketer Group, Nevada IEC/CC Washington, CAC.

[253]See, e.g., Requests for Rehearing of PacifiCorp, EPSA, PSNM. These issues are addressed elsewhere in this order.

[254]See, e.g., Requests for Rehearing of Marketer Group, PSNM, LADWP.

has not acted in accordance with its market-based tariff, the ISO and PX tariffs and the Commission's orders, there is no basis for the determination that the seller make refunds.

According to PSNM, just as purchasers must be on notice of the rates that they may be charged, the filed rate doctrine requires that sellers be on notice of the rules that will govern their rates. PSNM contends that the July 25 Order is at odds with this principle in two respects. First, PSNM cites the November 1 and December 15 Orders as informing sellers that their refund liability would be no lower than the seller's marginal costs or legitimate and verifiable opportunity costs and that the Commission assured sellers that to the extent their sales prices exceeded the relevant benchmark prices, they would be able to justify the prices based upon their cost of purchased power. Second, PSNM states that, under the December 15 Order mitigation plan that took effect on January 1, 2001, the refund potential for sellers would close within 60 days of the initial report unless the Commission notified the seller otherwise. PSNM asserts that it was not identified in the March 9 Order that its transactions were subject to refund, and, therefore, with respect to its sales into the ISO and PX markets beginning January 1, 2001, PSNM was not on notice of potential refund liability.[255]

Williams asserts that the order is at odds with principles of finality and certainty that the Commission cited in prior orders in this proceeding.

Marketer Group argues that each of the various price caps, breakpoints and proxy prices in effect since October 2 created a safe harbor below which sellers were assured that their charges would not be subject to refund. It contends that, if sales both above and below the price cap were equally subject to potential refunds under the refund effective date, then the price cap would have no meaning, nor could such an interpretation be harmonized with the Commission's determination that the market rules established the filed rate. Marketer Group argues that the Commission cannot reopen rates after they have become final and that the filed rate doctrine must be strictly enforced without regard to equitable considerations. It contends that the Commission is barred from retroactively adjusting the final rates in effect to reflect its later view of equitable prices under the mitigated Market Clearing Price mechanism announced in the June 19 Order.

Commission Response

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[255] Issues regarding 60 day refund notifications are addressed elsewhere in this order. See supra, section B.3.c.

We found in the November 1 Order that the "electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy . . . under certain conditions."[256] In the December 15 Order we reaffirmed this finding, and explained that, "[w]hile high prices in and of themselves do not make a rate unjust and unreasonable (because, for instance, underlying production prices may be high), if over time rates do not behave as expected in a competitive market, the Commission must step in to correct the situation."[257] We continued by finding that:

> independent of any conclusive showing of a specific abuse of market power, a variety of factors have converged to drastically skew wholesale prices under certain conditions: significant over-reliance on spot markets . . .; significant increases in load combined with lack of new facilities as well as reduced availability of supply from out of state; chronic underscheduling; and lack of demand responsiveness to price. . . . [W]e have no assurance that rates will not be excessive relative to benchmarks of producer costs or competitive market prices, due to the circumstances listed above.[258]

Moreover, we specifically found that an abuse of market power is not required for a determination that rates are unjust and unreasonable. Rather, whether prices are just and reasonable depends on whether those prices fall within a "zone of reasonableness."[259]

We reaffirm those findings. Our determination regarding the justness and reasonableness of the rates here is based on systemic dysfunctions in the single clearing price auction markets that resulted in those rates. We determined that structural problems, which existed in all hours, had the potential to cause market prices to exceed that which one would expect in a competitive market. While our solution requires review for all hours, that does not mean that this will result in refunds for all hours.

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[256] November 1 Order at 61,349-50; see also December 15 Order at 61,998.

[257] December 15 Order at 61,998-99.

[258] Id.

[259] Id.

Individual seller analysis was not required to find the rates unjust and unreasonable here, particularly as a single market clearing price applied to any given sale. All sellers received the same price. These circumstances make it appropriate to analyze all sellers as a whole. While the December 15 Order devised a remedy allowing individual sellers to justify prices above the "breakpoint," the underlying problem was that the single price auction, in conjunction with other components of market structure and market rules, was no longer producing just and reasonable rates.

FPA section 206(b) explicitly permits us to order refunds of any amounts paid in excess of those which would have been allowed under the just and reasonable standard. Sellers were or should have been aware that this statutory provision governed the rates of the sales at issue here. Under the rapidly changing circumstances here, where proceedings regarding the justness and reasonableness of the rates in the PX and ISO markets were instituted in August, 2000, with a refund effective date in October 2000, the beneficial effects of rate certainty must yield to the Commission's statutory obligation to ensure that rates do not exceed the zone of reasonableness. As Commission orders are not final while subject to rehearing, and rehearing was requested of all orders in this proceeding, the mitigation measures and related procedures implemented in those orders were subject to adjustment or replacement. Sellers could not reasonably have expected therefore, that the mitigation measures and related procedures implemented in earlier orders in this proceeding would remain unchanged during the rehearing process.

Due process has been satisfied in this case. As the voluminous record in this case illustrates, parties were provided with a full opportunity to address refunds and all other issues in this case. We fully considered all proper submissions, and this record provides sufficient discussion of the issues so that we can appropriately decide all issues in this case on the resulting record.

b. Applicability of Refunds to APX

APX, a power exchange, argues that the Commission should not impose refunds on sellers that do not own generation. Specifically, APX contends that it had no ability to exercise market power since it only served as an intermediary between the generators and the PX.

Commission Response

By letter order issued on August 10, 2001, the Commission determined to leave the issue of APX's role in the hearing established in the July 25 Order, including APX's liability, if any, for refunds and APX's obligation, if any, to provide data, to the presiding

administrative law judge in the first instance. We will address this issue, if necessary, after the judge addresses it in the refund proceeding.

c. Issues from December 15 Order

Several issues related to refunds remain from the December 15 Order. First, several suppliers oppose the December 15 Order's determination to adopt, over their objections, the November 1 Order's proposal to "condition market-based rates on sellers remaining subject to potential refund liability through December 31, 2002[260] in order to ensure just and reasonable rates during the period it takes to effectuate longer term remedies in the markets."[261] They renew their argument that it was beyond the Commission's authority under section 206(b) of the FPA to extend potential refund liability for more than 15 months from the refund effective date.[262] For example, Dynegy argues that: the general duty imposed by section 206(a) is to be implemented only in accordance with the substantive and procedural limitations of section 206(b); the opportunity to obtain refunds, as well as limitations on refund effective dates, are created by section 206(b) and are not mentioned in section 206(a); once a rate is accepted for filing and that rate is challenged by the Commission or another market participant under section 206, then the limitations of section 206 apply; Central Iowa Power Cooperative v. FERC[263] is distinguishable because, although the court held that the Commission had authority to amend the power pooling agreement pursuant to section 206, the court's decision did not concern the extent of the Commission's refund authority; although the courts have recognized that imposing a condition can be preferable to the alternatives of rejection or unconditional acceptance, the Commission has steadfastly refused to reject market-based rates, and the Commission approved Dynegy's market-based rate without suspension or hearing; the Trans Alaska case[264] is distinguishable because it was an Interstate Commerce Act (ICA) case, not an FPA case, the 15-month refund provision was recently added to the FPA and Trans Alaska involved the ICA equivalent of an FPA

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[260]The Commission subsequently provided for price mitigation, which includes potential refund liability, to run through September 30, 2002. See June 19 Order, 95 FERC at 62,567.

[261]See December 15 Order, 93 FERC at 62,010-11.

[262]See, e.g., Requests for Rehearing of Dynegy at 18-26, Enron at 9-10, PPL at 18-21, and Reliant at 16-18.

[263]606 F.2d 1156 (D.C. Cir. 1979) (Central Iowa).

[264]See Trans Alaska Pipeline Rate Cases, 436 U.S. 631 (1978).

section 205 rate approval rather than an FPA section 206 rate adjustment; the Yankee Atomic case[265] is distinguishable because there the Commission required amendment of the utilities' base rates to allow for refunds if a limited component, the return on equity component, of their formula rates exceeded a certain level; and section 206(a) does not provide an independent source of refund conditioning authority because it does not explicitly reference refunds, the Commission is attempting to do indirectly what the FPA does not permit it to do directly.[266]

Reliant argues that the refund condition is improper because the December 15 Order ordered the implementation of market structural remedies to assure just and reasonable rates going forward. Further, it contends that under section 206(b), once the Commission has put into place the conditions for just and reasonable rates "to be thereafter observed," the refund period is closed, and prospective refunds are precluded by the mechanics of the FPA. Further, it contends that the types of conditions placed on authorization of market-based rates relate not to the price charged but to the structure and restrictions of market interactions, such as the requirement that an applicant file and operate pursuant to an open-access tariff or file regular reports regarding contractual relationships with affiliates so that the Commission can insure that a party is not exercising market power. It also argues that the uncertainty of whether a certain price will meet an after-the-fact "just and reasonable" evaluation would discourage new investment in needed resources. If any refund obligation is retained, Reliant argues that it should apply only to transactions that occurred between October 2, 2000 and December 31, 2000, and transactions at prices above the $150/MWh breakpoint after December 31, 2000 that are evaluated by the Commission during the rolling sixty-day refund period.

PPL also objects to the imposition of refund liability as a condition on the market-based rate authority of sellers that the Commission did not find specifically to have exercised market power. The City of San Diego conversely asserts that ending refund liability at the end of December 2002, without evidence that rates being charged after that date would be just and reasonable, was improper. The California Commission and the County of San Diego allege that the 60-day window for above-breakpoint transactions, after which refund liability will end absent written notification from the Commission, improperly restricts sellers' refund obligations, and they complain that buyers will not have access to data in that time frame to be able to challenge the rates

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[265]See Yankee Atomic Electric Co., 40 FERC ¶ 61,372 (1987).

[266]Further, Dynegy argued that the need for prospective refunds should be reassessed based on the outcome of the conference on forward contracting in Docket No. PL01-2-000 that commenced in December 2000. However, the conference was suspended on January 10, 2001.

charged. The City of San Diego also argues that the Commission must either order refunds immediately or give a reasonable basis for the delay.

Commission Response

We deny rehearing on these issues. The parties' emphasis on section 206(b) is misplaced. As discussed in greater detail in the November 1 Order,[267] Congress passed the Regulatory Fairness Act (RFA), establishing the 15-month refund effective period, in order to give the Commission authority to order retroactive rate reductions in section 206 proceedings.[268] Nothing in the RFA or its legislative history suggests that Congress intended to address, much less limit, the Commission's pre-existing authority to order prospective relief. Since the RFA has no bearing on this issue, cases cited by the Commission concerning its prospective conditioning authority carry the same precedential weight regardless of whether they were decided before or after the enactment of the RFA. Therefore, section 206(b) does not limit the Commission's prospective conditioning authority. Further, the fact that Central Iowa did not specifically address refund conditions for market-based rates does not prevent the application of its broader holding - that the Commission may amend rates pursuant to section 206 -- to these facts. The fact that Yankee Atomic applied to one component of a formula rate is irrelevant; the Commission had authority to change the rate under section 206.

Further, Dynegy's argument that section 206(a) does not mention refunds is also misplaced, because section 206(a) authorizes the Commission to fix the just and reasonable rate, charge, classification, rule, regulation, practice or contract to be thereafter observed. Having found that "the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight"[269] and that long-term measures needed to be developed, the Commission could not lawfully

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[267] See 93 FERC at 61,379-80.

[268] Prior to enactment of the RFA, the Commission's authority under section 206 was limited to prospective relief. Congress took note of the fact that section 205 proceedings, in which proposed rate changes are subject to refund, took on the average of one year to complete, but section 206 proceedings, in which rate reductions could be ordered prospectively only, took on the average of two years to complete. It concluded that one probable reason for the difference was that public utilities had little incentive to settle meritorious section 206 complaints since any relief was prospective. See S. Rep. No. 100-491, 1988 U.S. Code & Cong. Ad. News 2684-85.

[269] Id. at 62,011.

ensure just and reasonable market-based rates in the ISO and PX markets in the interim period absent the imposition of a refund condition. Consequently, any refunds would be pursuant to the sellers' continuing market-based rate authorizations, not section 206(b). Since the December 15 Order instituted interim remedial measures, we reject Reliant's argument that the order's mitigation measures made a refund condition unnecessary.

Whether conditions on market-based rate authorization ordered previously in other cases included refund conditions does not affect our authority to impose refund conditions to ensure just and reasonable rates here. We find that the need for the refund condition here to address the dysfunctional markets outweighs the potential that refund uncertainty might dissuade some potential sellers from new investment in generation in California.

Even if we agreed with the view that the 15-month limitation on refunds under section 206(b) applied to prospective relief, and we do not, the argument concerning the December 15 Order's conditioning of suppliers' continued market-based rate authority on a refund obligation through December 31, 2002 has been rendered moot by subsequent Commission orders. The temporary price mitigation measures adopted in the December 15 Order were superseded, effective May 29, 2001, by the long-term price mitigation measures adopted in the April 26 Order and further modified in subsequent orders. The April 26 Order replaced the December 15 Order's market monitoring requirement for monthly reports filed by the ISO with a formula-based mitigated reserve deficiency MCP. The April 26 mitigation plan made sales above the mitigated price occurring in a given month subject to refund pending Commission review of sellers' cost justification filings for that month.[270] Thus, effective May 29, 2001, the date that the April 26 mitigation took effect, sellers' refund obligation was pursuant to the April 26 Order's cost justification filing requirement rather than pursuant to the December 15 Order's ongoing market monitoring.[271] Since the refund condition adopted in the December 15 Order remained in existence for only five months, it did not exceed the 15-month limit under FPA Section 206(b). Accordingly, arguments based on a premise that the limit was or would be exceeded are moot.

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[270]The Commission also conditioned sellers' market-based rate authority on their not engaging in certain anticompetitive behavior, with violators' market-based rates being made subject to refund.

[271]Refunds for transactions occurring during non-reserve deficiency hours from May 29 through June 20, 2001 will be calculated in the refund hearing before Judge Birchman. See July 25 Order, 96 FERC at 61,517.

City of San Diego expresses concern that the December 15 Order does not ensure that sellers' rates would be just and reasonable after the termination of their potential refund liability. Its concern was premature in view of the interim nature of the December 15 Order. As noted above, even though the June 19 price mitigation is set to end on September 30, 2002,[272] quarterly reporting by the ISO will continue. If the quarterly reports reveal the potential to exercise market power, the Commission will determine any appropriate action to take.

We reject PPL's argument that we may not impose refund liability absent a finding that a specific seller exercised market power for the same reasons that we reject the same argument on rehearing of the July 25 Order.[273]

The parties' argument that the 60-day window for review of transactions above the mitigated price is too restrictive is moot.[274] In the June 19 Order, in response to similar concerns, we explained that the 60-day period for review of cost justifications was a self-imposed requirement to ensure that there is price certainty and that we have the authority to extend the period if necessary to finish processing the justifications.[275] To date, we have processed cost justification filings without extending the 60-day window of review.

With respect to City of San Diego's argument that we should have ordered refunds immediately, the record was not sufficiently developed at the time of the December 15 Order to take such action. As noted earlier in this order, the Commission established a refund hearing in this proceeding.

d. Issues from June 19 Order

APPA contends that limiting price mitigation to spot market sales of 24 hours or less unreasonably truncates the scope of potential refunds. The ISO claims that the June 19 Order fails to adequately address refunds for past overcharges by sellers.

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[272]June 19 Order, 95 FERC at 62,567.

[273]See supra section B.3.a.

[274]As noted above, the December 15 Order's provision for reporting transactions above the $150 breakpoint has been replaced with the requirement that sellers make cost justification filings for sales above the mitigated price.

[275]95 FERC at 62,566.

BP Energy Company contends that the refund obligation is imposed on mutually agreed, bilateral sales transactions without required evidentiary findings that such sales are not just and reasonable. Idacorp and Williams request clarification that the June 19 methodology will not be applied retroactively. Idacorp requests, at least, clarification that the methodology will not be applied retroactively unless the Commission has further proceedings to develop a fact-based methodology. In addition, Idacorp requests clarification to reaffirm that rates may be justified by costs, and that sellers have the right to setoff against any refund amounts. PPL asks the Commission to abide by its commitment to notify sellers within 60 days of their reports if it may impose refund liability. Puget Sound requests confirmation that the refund effective date for sales outside of California is not prior to July 2, 2001. Sierra Pacific and Nevada Power request clarification that they should have no refund obligation for past sales into California.

AEPCO claims that there is no basis for applying provisions under the June 19 Order retroactively to out-of-California sellers that are not public utilities and forcing such sellers to undergo any sort of overcharge/refund inquiry.

Washington Attorney General and several other parties contend that the Commission should have established a refund effective date for West-wide refunds consistent with the refund effective date for California refunds. Washington Attorney General argues that (1) the original San Diego proceeding has always been, effectively, considered as a West-wide proceeding; (2) excluding Northwest utilities from potential refunds from October 2, 2000 would lead to refund anomalies that would be inconsistent with the FPA's policies against a seller giving preferential treatment to any purchaser and against any advantages to any person based on geographic locality; and (3) the Puget Sound proceeding provides a basis for an earlier refund effective date.[276]

Commission Response

We deny these requests for rehearing and grant or deny requests for clarification, as discussed below. In view of Commission determinations in the July 25 Order, some of these issues are either moot or subsumed within the discussion of requests for rehearing of the July 25 Order, which are discussed elsewhere in this order.[277]

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[276] See also Requests for Rehearing of Idaho Power, North Star Steel, Attorney General of Washington/City of Tacoma, Washington, and Port Seattle, Washington

[277] Regarding AEPCO's argument concerning bilateral transactions, this order (see sections B.1, E.10) affirms the determination to apply the refund methodology to

(continued...)

APPA contends that the Commission's investigation should encompass all public utility sales for resale at market-based rates and all transactions of less than one year. The spot markets were the only markets in which the Commission determined that rates may be unjust and unreasonable.[278] Therefore, it was appropriate to limit mitigation to those markets. Moreover, APPA provides no justification to extend the scope of our investigation or the mitigation to bilateral transactions other than those in spot markets.[279]

With respect to the ISO's arguments that the June 19 Order fails to adequately address refunds for past overcharges, we note that the July 25 Order established a methodology for calculating refunds from October 2, 2000 through June 20, 2001 and a hearing before Judge Birchman to develop the factual record in order to implement it.

We also provide the following clarifications. First, price mitigation, as modified by the July 25 Order, will be applied to the period from October 2, 2000 through June 20, 2001.[280] Second, for prospective price mitigation, all sellers in the ISO spot markets and all public utility sellers for bilateral spot market sales in the WSCC through September 30, 2002 seeking to charge prices in excess of the mitigated price may make cost justification filings pursuant to the procedures set forth in the April 26 and June 19 Orders and this order.[281] Third, the June 19 Order stated that the 60-day review period was self-imposed, and we reserved the right to take more time, if necessary to finish

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[277](...continued)
transactions by governmental entities and cooperatives in the ISO and PX markets, but grants rehearing and determines that those sellers are not required to make refunds for transactions outside of the ISO and PX markets.

[278]The spot markets are short-term (i.e., one day or less) energy markets (Day-Ahead, Day-of, Ancillary Services and real-time energy sales). See November 1 Order, 93 FERC at 61,349; June 19 Order, 95 FERC at 62,545, n.3).

[279]See 95 FERC at 62,556.

[280]As noted supra note 260, refunds for transactions occurring during non-reserve deficiency hours from May 29, 2001 through June 20, 2001 will be calculated in the refund hearing before Judge Birchman.

[281]The April 26 Order established the cost justification filing mechanism. The June 19 Order, among other things, modified the April 26 Order with respect to the types of costs that would be allowed.

processing the justification filings.[282] In any event, a self-imposed procedural deadline could not preclude us from ordering refunds where necessary to fulfill our duties under section 206.

Concerning Puget Sound's request for clarification that the refund effective date for sales outside of California is not prior to July 2, 2001, we note that the April 26 Order which initiated the West-wide investigation of sales in the WSCC established a refund effective date of July 2, 2001.[283] However, we further note that the July 25 Order established a separate proceeding (in response to Puget Sound's complaint) to address whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. Puget Sound has filed a motion to withdraw its complaint in that proceeding. If the Commission denies Puget Sound's motion to withdraw its complaint, then the Commission could establish a refund effective date as early as December 25, 2000, with respect to rates in the Pacific Northwest.[284] Thus, there remains the potential for some overlap, with respect to rates in the Pacific Northwest, between the Puget Sound complaint and the West-wide investigation. The complaint, and the motion to withdraw the complaint are pending. At present, the only operative refund effective date is July 2, 2001 with respect to the West-wide investigation.

We deny Sierra Pacific's and Nevada Power's request for clarification that they should have no refund obligation for past sales into California. In the July 25 Order, the Commission determined that refund liability should apply to all sellers of energy in the ISO and PX spot markets for the period beginning October 2, 2000.[285]

With respect to Washington Attorney General's argument that the refund effective date for West-wide refunds should be consistent with the refund effective date for California refunds, we note that the July 2, 2001 refund effective date established for the

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[282] See 95 FERC at 62,566.

[283] See June 19 Order, 95 FERC at 62,567-68, 62,570 (noting that the date 60 days after Federal Register publication of notice of the investigation initiated by the April 26 Order was July 2, 2001).

[284] See 96 FERC at 61,520-21 & n.75. December 25, 2000 is the earliest refund effective date the Commission could establish for Puget Sound's complaint regarding rates in the Pacific Northwest.

[285] See 96 FERC at 61,511.

West-wide investigation initiated in the April 26 Order was 60 days after Federal Register publication of notice of initiation of the investigation, which is the earliest refund effective date permitted under section 206(b) of the FPA.[286]

Further, we disagree that the original SDG&E complaint proceeding was effectively a West-wide proceeding. The SDG&E complaint concerned rates for SDG&E's purchases through the ISO and PX markets in California. The Commission did not establish a West-wide investigation until it issued its April 26 Order.

e. Issues from July 25 Order

The ISO seeks clarification that the July 25 Order does not require a full refund period netting approach for settlement of refunds. The ISO contends that by allowing sellers to net against refund amounts they owe past due payments and possibly refund amounts owed to them by sellers, without consideration of timing or parties involved, the Commission would be giving sellers who charged unjust and unreasonable rates first collection priority over refund amounts. Instead, the ISO asserts that the Commission should refer to the hearings on refunds the issue of how refund amounts should be calculated and paid, and must indicate that the resolution of the issue must not give sellers an unfair advantage.

Other clarifications sought include whether the refund amounts owed by suppliers are to be offset by the amounts due to suppliers,[287] whether any refunds need to be paid if a purchaser has failed to pay for its purchases,[288] and by what mechanism refunds should flow through to purchasers.[289]

Commission Response

The July 25 Order provides in pertinent part:[290]

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[286] Id. at 61,520 n.75.

[287] See, e.g., Request for Rehearing of Salt River.

[288] See, e.g., Request for Rehearing of Puget/Avista.

[289] See, e.g., Request for Rehearing of City of San Diego, Vernon.

[290] 96 FERC at 61,519.

> Once the ISO has calculated the hourly market clearing prices for the refund period, this data should be used by both the ISO and PX to rerun their settlement/billing processes and all penalties. These revised settlements should be submitted to the administrative law judge and parties should use this information to form the basis of any offsets (i.e. the amounts to be refunded against the payments past due). We direct the administrative law judge to certify this information, in its entirety, to the Commission.
>
> California Parties support the calculation of interest against refunds and maintain that Commission precedent requires an interest calculation. Sellers believe that if interest charges are assessed that they should be assessed symmetrically to refunded amounts and to amounts past due. We will direct the calculation of interest on both refunds and receivables past due, pursuant to the methodology for the calculation of interest under Section 35.19a of the Code of Federal Regulations.[[291]]

With respect to the requests for clarification or rehearing concerning offsets, and whether a seller must make refunds even when a purchaser has failed to pay for its purchases, we note that the July 25 Order provides for offsets of amounts to be refunded against payments past due, as discussed above. The July 25 Order balanced the interests of those who would receive refunds and those who would have to pay refunds by directing the calculation of interest on both refunds and receivables past due. The ISO does not explain, and we do not see, how this offset approach would give sellers who charge unjust and unreasonable rates first collection priority over refund amounts, as the ISO asserts, and the ISO has not persuaded us that this approach will not adequately protect the interests of those who will receive refunds.

The July 25 Order does not specify the mechanism by which refunds should flow to customers. We will address this issue when, after reviewing the judge's findings of fact in the refund hearing, we issue an order addressing refunds.

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[291] The July 25 Order also established an evidentiary hearing to further develop the factual record to enable the refund methodology prescribed in the order to be implemented, and it generally limited the scope of the evidentiary refund hearing to the collection of data needed to apply the refund methodology prescribed in the order. Id. at 61,520.

PG&E reiterates its argument that refunds should be ordered for the pre-October 2000 period. The July 25 Order denied PG&E's and others' requests for rehearing of the November 1 Order on that issue, and PG&E makes no new arguments that cause us to reconsider our determination that the Commission is not authorized to order refunds prior to the October 2 refund effective date.

C. Rehearing of Remaining Issues from December 15 and Earlier Orders

Many arguments regarding the proposed remedies in the November 1 Order were never ripe for rehearing. In the November 1 Order, the Commission merely proposed actions or tariff changes. Commission proposals do not trigger administrative review, and rehearing does not lie until the Commission issues a final decision or other final order.[292] In any event, the events and orders transpiring since the beginning of this proceeding have resolved or made moot many issues the parties have raised. For example, since deadlines that the Commission imposed in the November 1 Order for the implementation of various Commission directives have passed, and no consequences were imposed for not meeting those deadlines, the arguments concerning the impracticality of these deadlines are now moot. Furthermore, the market mitigation plan established in the April 26 and June 19 Orders has now superseded prior Commission directives, and the refund methodology adopted in the July 25 Order has now superseded the $150/MWh breakpoint approach of the December 15 Order. Thus, most of the issues raised on rehearing with respect to the mitigation and reporting requirements of the December 15 Order are moot.

1. Buy/Sell Requirement

The December 15 Order eliminated the requirement that the IOUs sell all of their generation into and buy all their generation from the PX ("buy/sell requirement"). In order to enforce this remedial measure, the Commission also terminated the PX's wholesale rate schedules, noting the California Commission's reluctance to remove its mandatory buy requirement, and finding that the Commission could not ensure just and reasonable rates in the presence of a mandatory power exchange in those circumstances. The Commission later clarified that only the PX's spot market rate schedules (core

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[292] See Rule 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713 (2001).

markets) needed to terminate, and that the PX's forward markets (CTS Rate Schedules) could continue in a modified form.[293]

The PX contends that the Commission overstepped its statutory and Constitutional authority when it ordered the end to the PX's rate schedules. Specifically, the PX states that FPA section 206 authorizes the Commission to examine the justness and reasonableness of any wholesale rate schedule, and if it finds that a rate is unjust and unreasonable, the Commission shall prescribe substitute terms or conditions. The PX argues that the Commission has a statutory duty to allow a public utility to continue in business and to prescribe just and reasonable terms under which that can occur.

In stating that the Commission's cancellation of the PX's rate schedules is unconstitutional, the PX contends that it has a "fundamental right not to have its property taken without due process and just compensation," since "every public utility is entitled to an opportunity to recover its costs of doing business and a fair rate of return on its capital." Finally, the PX argues that the termination of the CTS Rate Schedule was unnecessary and that clarification is needed to distinguish between the mandatory PX core markets and the voluntary CTS Block Forward Markets.

In order to address some of its concerns, the PX requests that the Commission stay two actions taken in the December 15 Order. First, the PX requests that the Commission stay its action preventing the IOUs from continuing to sell power into the PX markets on a voluntary basis. Second, the PX asks that the Commission stay its termination of the CTS Block Forward Rate Schedule to prevent a chilling effect on long-term contracts.

The Oversight Board states that the termination of the PX tariff needlessly eliminates market opportunities for buyers and sellers, when, in the alternative, the Commission could have simply eliminated the mandatory buy/sell requirement.[294] The California Commission contends that the Commission erred in eliminating the PX's buy-sell requirement since this action violates the FPA, is arbitrary and capricious, is not the

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[293] See San Diego Gas & Electric Co., 94 FERC ¶ 61,005, reh'g dismissed, 94 FERC ¶ 61,243 (2001) (January 8, 2001 Order).

[294] In addition, the Oversight Board contends that the Commission's actions, in removing the utilities' supply from the PX spot markets, intrude upon the California Commission's jurisdiction over the manner in which the revenues associated with utilities' sales of energy are allocated. Specifically, the Oversight Board states that without utilities purchasing their own supply from the PX, the California Commission loses its exclusive jurisdiction over how the utilities' revenues are treated: either as benefits to a utility's shareholders or ratepayers.

product of reasoned decisionmaking, and is not based on substantial evidence. SMUD argues that, since the Commission's prohibition against the IOUs selling into the PX markets may be "undermined" if the PX's Motion to Stay this prohibition is granted by the 9th Circuit, it is an inadequate measure to ensure just and reasonable rates. Finally, SDG&E seeks clarification that the Commission intended to eliminate only the requirement that IOUs bid their resources into the PX market, thus permitting IOUs to rely on their own resources to serve their retail load, and not to forbid IOUs from selling into the PX market any surplus resources that are not needed to serve that load.

Commission Response

The Commission finds that its actions eliminating unjust and unreasonable rates through removal of the reliance on the buy/sell requirement lawfully followed the procedures dictated in FPA section 206. Under FPA section 206, the Commission can investigate existing rates, and, if it finds those existing rates unlawful, set new just and reasonable rates. In response to numerous formal and informal complaints, comments, and inquiries, and following the Commission's paper hearing and an investigation of the serious economic impact that the existing wholesale market structure was having on California, the Commission determined that the buy/sell requirement created a dysfunctional wholesale spot market with considerable volatility. In light of this finding, the Commission concluded, pursuant to FPA section 206, that it was no longer just and reasonable to permit virtually all of the IOUs' needs to continue to be met in the wholesale spot market.

However, when faced with the California Commission's unwillingness to relinquish reliance on the buy/sell requirement, the Commission "conclude[d] that it is necessary to take the unusual step of terminating the PX's wholesale tariffs which . . . enable it to continue to operate as a mandatory exchange."[295] Thus, once the Commission determined, pursuant to FPA section 206, that the PX's mandatory exchange rates were unlawful, the Commission properly tailored relief to eliminate the problem through termination of the PX's wholesale tariffs. This relief action that the Commission contoured to address the identified harm, was a critical part of the comprehensive set of remedies for the serious flaws in the California market structure and rules that have caused and could have continued to cause unjust and unreasonable rates for short-term wholesale sales of electric energy in interstate commerce. Through the remedies ordered in the December 15 Order and orders issued thereafter, the Commission determined "the just and reasonable rate, charge, classification, rule, regulation, practice or contract" to

[295]December 15 Order at 61,999

replace the flawed structure and rules and "fix[ed] the same by order," as required by FPA section 206.

Furthermore, the Commission has not closed the PX for business, despite the PX's contention that the effect of the December 15 Order was to do so. In fact, in the December 15 Order, the Commission invited the PX "to reconstitute itself as an independent exchange with no regulatory mandated products and offer the services needed by market participants."[296] Also, in the January 8, 2001 Order, the Commission clarified "that our determination to terminate the PX's existing wholesale rate schedules was not intended to preclude the PX from engaging in bilateral forward contracting."[297] We went on to state that the "PX is free to revise its CTS tariffs to remove the spot market components of its existing rate schedules, and to file them" pursuant to FPA section 205.[298] In addition to demonstrating that the Commission has not closed the PX, these clarifications in the January 8, 2001 Order render moot the PX's request that the Commission stay its termination of the CTS Block Forwards Rate Schedule.

The Commission also must deny the PX's request that the IOUs be allowed to voluntarily sell power into the PX markets. In order to assure just and reasonable rates in the presence of the state-mandated requirement that the IOUs sell all of their generation into and buy all of their generation from the PX, and in light of the state's established policy favoring the use of the spot markets, the Commission found it necessary and continues to believe it necessary to terminate the PX's Core Markets rate schedules as clarified in the January 8 Order. To do otherwise would be to allow a state requirement to override the Commission's mandate to assure just and reasonable rates for sales within the Commission's exclusive jurisdiction.[299]

The PX is also incorrect in stating that the Commission's action "is unconstitutional because it violates the PX's fundamental right not to have its property taken without due process and just compensation." In Jersey Central Light & Power Co.

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[296]Id. at 62,000, n.46.

[297]January 8, 2001 Order at 61,008.

[298]Id.

[299]While the PX argues that the "absolute prohibition contravenes the December 15 Order's stated objective of promoting forward trading opportunities," the Commission addressed this concern in the January 8 Order when it clarified that its action "was not intended to preclude the PX from engaging in bilateral forward contracting." 94 FERC at 61,008.

v. FERC, 810 F.2d 1168 at 1180-81 (D.C. Cir. 1987), the court stated that "a company that is unable to survive without charging exploitative rates has no entitlement to such rates." Since the PX's tariff led to unjust and unreasonable rates under certain conditions, it has no constitutional right to retain that tariff. Also, since the PX has recovered its $100 million startup costs and the opportunity was available to recover ongoing operating expenses through its tariff,[300] no takings issue exists.

Finally, we note that, in considering the PX's arguments in a petition for mandamus in this proceeding, the United States Court of Appeals for the Ninth Circuit stated that "[w]e are unconvinced that CalPX [PX] has presented a 'clear and certain' claim that FERC violated section 206(a) by terminating its tariff and rate schedules." California Power Exchange Corp. v. FERC, 245 F.3d 1110, 1121 (9th Cir. 2001). Indeed, the court found that terminating the PX's tariff and wholesale rate schedule "to prevent it from continuing to operate as a mandatory exclusive exchange," along with the other remedies in the December 15 Order "appear to be fully consistent with § 206(a). Id.

In our December 15 Order and subsequent orders, the Commission has established rates, regulations or practices which we believe result in just and reasonable rates.

2. Underscheduling

In the December 15 Order, the Commission adopted an underscheduling penalty to apply to market participants that met more than five percent of their load in the real-time markets. The California Commission, ISO, SMUD, the Oversight Board, and PG&E request rehearing of the underscheduling penalty, stating that the penalty should either account for good utility practice, apply symmetrically to generation not scheduled in forward markets, or should be eliminated. The California Commission states that the decision in the December 15 Order rests on internally inconsistent factual assertions and that the penalty will exacerbate the exercise of market power by the suppliers. Further, the California Commission opposes the distribution of proceeds from the underscheduling penalty to loads that schedule accurately because only those loads that are self-sufficient in generation will benefit due to the lack of adequate supply offered in the PX markets. The California Commission asserts that these self-sufficient loads have an incentive to withhold supply from the market to increase the revenues they receive from the underscheduling penalty. The Oversight Board argues that the penalty is unlikely to reduce underscheduling and may increase costs in the forward markets.

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[300] See PX FERC Electric Tariff, Third Revised Volume No. 1, Schedule 1, Original Sheet Nos. 48-49.

SDG&E and PG&E contend that other aspects of the December 15 Order crippled the ability of suppliers to use short-run coordinated markets to balance supply and demand, and thus made it impossible for suppliers to avoid the underscheduling penalty. The two companies jointly filed a request in Docket No. EL01-34-000 seeking suspension of the underscheduling penalty. The Commission deferred action on the request and sought additional information from the ISO, which the ISO has since submitted.[301] The matter remains pending before the Commission.

On rehearing of the December 15 Order, the ISO expresses support for incentives, such as the underscheduling penalty, to move both load and generation into forward purchases, but suggests that the December 15 Order does not apply these incentives symmetrically, and should also include incentives to move generation out of real-time markets. The ISO also filed in Docket Nos. ER01-1579-000 and ER01-1579-001, Amendment No. 38 to temporarily suspend the penalty for underscheduled load because severe financial difficulties of PG&E and SoCal Edison prevented them from making bilateral purchases or accessing forward markets. The Commission, among other things, rejected the proposed tariff amendment on the basis that the matter was pending in Docket No. EL01-34-000.[302] Parties sought rehearing of the Commission's decision.

Commission Response

The Commission has long had penalties in Open Access Transmission Tariffs to encourage balanced schedules. In the December 15 Order, the Commission recognized that the lack of forward purchases and any resulting underscheduling of load threatened the reliability of the ISO controlled system by forcing over-reliance on the ISO's real-time imbalance markets to supply load. Therefore, the Commission adopted the penalty provision as one component of the market mitigation to encourage forward contracts and a more balanced supply. Subsequent to the issuance of the December 15 Order, the State of California and DWR began negotiating forward purchases on behalf of SoCal Edison and PG&E to cover their net short position (i.e., the load remaining to be served after the utilities had self-supplied generation).

We will grant rehearing on this issue and will eliminate the underscheduling penalty for load as of January 1, 2001, when it was to have been implemented pursuant to the December 15 Order. As noted by intervenors, the suspension of operation of the PX

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[301] See Southern California Edison Company and Pacific Gas & Electric Company, 95 FERC ¶ 61,025 (2001).

[302] See California Independent System Operator Corporation, 95 FERC ¶ 61,199 (2001), reh'g pending.

Day-Ahead and Hour-Ahead markets, and the slow development of markets to fill this void, has limited the ability and flexibility of loads to fill their requirements for energy in the day ahead and hour ahead time frames. The Commission does not wish to penalize market participants for underscheduling when markets may not have been available to fulfill their needs; it would be unreasonable to impose a penalty in a situation where that penalty could not be avoided. In any event, we have seen a vast improvement in the reduction of underscheduling by loads, especially in the summer months, when historically underscheduling has been most noticeable. There do not appear to have been any underscheduling penalty payments made or distributed. Forcing such payments at this late date will have no effect on past behavior, and the markets have now seemed to stabilize with the combined effects of the other features of our orders. Therefore, although accurate scheduling is still paramount, as both underscheduling and overscheduling can present severe problems in reliable operation of the ISO's system, the underscheduling penalty should be eliminated.

We will not hesitate to impose prospectively a similar penalty if chronic underscheduling again creates a reliability problem in California, although we believe this scenario is unlikely since overall supply and demand are now more in balance and the must-offer obligation will remain in place through September 30, 2002.

In light of this determination, we find the ISO's Tariff Amendment No. 38 filed in Docket Nos. ER01-1579-000 and -001 proposing to suspend the penalty to be moot, and we will terminate that docket. Similarly, we will dismiss the complaint in Docket No. EL01-34-000 as moot.

3. QF Issues

The December QF order waived certain regulations to allow QFs to sell their excess production to load located in California in order to alleviate the inadequate generation resources. The order also provided that additional power generated as a result of the waivers above historical output was to be sold through negotiated bilateral agreements. SoCal Edison filed a request for immediate modification of the order, claiming that permitting sales of excess production interfered with existing contractual relationships, created uncertainty between the parties, and was unworkable given the short time period for the waiver (less than a month). SoCal Edison requested that the Commission limit its order to waiving efficiency and fuel use standards, and allow the parties to determine how the waiver would impact their contractual rights and obligations, including whether to negotiate a contract amendment.

In the December 15 Order, the Commission extended the waiver of those regulations through April 30, 2001.[303] IEP states that it generally supports the Commission's actions in the December 15 Order. IEP states, however, that some statements in the Commission's December 15 Order could lead to unintended consequences, including QF power becoming unavailable to serve the California market as a result of the California Commission repricing existing long-term QF contracts. IEP asks the Commission to clarify that PURPA pricing provisions still apply to the sale of QF electric power following the December 15 Order.

CE Generation expresses similar concerns. CE Generation states that the California Commission has indicated that it intends to regulate QFs in ways inconsistent with PURPA, including requiring QFs to sell power at rates lower than those contained in existing long-term QF contracts. CE Generation asks the Commission to declare that the California Commission does not have jurisdiction to regulate the price of power sold at wholesale pursuant to long-term contracts that were entered into pursuant to PURPA and that the California Commission must allow California IOUs to recover the costs of their purchases made pursuant to such long-term contracts.

Commission Response

As we stated above in our discussion addressing the rehearings of the June 19 and July 25 Orders,[304] QFs are not being compelled to make sales inconsistent with the pricing provisions of PURPA. The QFs' primary sales remain sales pursuant to contracts either freely negotiated between parties and containing negotiated rates or pursuant to contracts imposed under PURPA and at avoided cost rates set by the State Commission.[305] Nothing in our December 15 Order interferes with existing long-term contractual arrangements between QFs and utilities. The pricing provisions contained in the long-term contracts remain in effect unless a state court or a bankruptcy court finds that the contracts have been breached and are no longer in effect. New contractual arrangements for the sale of "excess power" must be pursuant to bilateral contracts with negotiated rates. In sum, PURPA pricing provisions remain in place following the

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[303]The Commission later extended the waiver through April 30, 2002, and we extend it elsewhere in this order through December 31, 2002. See Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272, order on reh'g, 95 FERC ¶ 61,225 at 61,767-68, order on further reh'g, 96 FERC ¶ 61,155, order on further reh'g, 97 FERC ¶ 61,024 (2001).

[304]See supra, section B.1.b.

[305]See 18 C.F.R. § 292.301- 292.304 (2001).

December 15 Order, as we foresee no sales resulting from our December 15 Order which would take place at rates inconsistent with our regulations implementing PURPA.

Regarding CE Generation's issues, we note that one of the principal benefits of QF status is that QFs are exempt from much state law and regulation, including rate regulation (other than regulation implementing our avoided cost regulations contained in 18 C.F.R. §§ 292.301 - 292.308 (2001)).[306] We also note, as CE Generation points out, that courts have addressed the relationship between state regulation and this Commission's authority with respect to PURPA on a number of occasions.[307] Our regulations also provide that, upon the request of any person, the Commission may determine whether a QF is exempt from a particular state law or regulation.[308] While we stress that our orders addressing the California energy crisis were not intended to require QF power sales at prices inconsistent with PURPA, we have not been presented in this rehearing with details of any specific state action inconsistent with PURPA. Nor have we before us a request that we determine whether a QF is exempt from a particular state law or regulation. Accordingly, we decline to make any declarations at this time about any proposed California Commission action. We will clarify that the Commission was not authorizing in its December 15 Order any state action inconsistent with PURPA.

4. Governance of the ISO

In the December 15 Order, the Commission required that the existing stakeholder ISO Governing Board be replaced with a non-stakeholder Governing Board whose members are "independent of market participants."[309] The order called for "further on-the-record procedures to discuss with California representatives the selection process for the new ISO Board."[310] Pending those discussions, the ISO Governing Board was to turn over decision-making power and operating control to the management of the ISO by January 29, 2001, and subsequently serve as a stakeholder advisory committee until the

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[306] See 18 C.F.R. 292.602(c) (2001).

[307] See, e.g., Independent Energy Producers Association v. California Commission, 36 F.3d 848 (9th Cir. 1994); Freehold Cogeneration Association v. Board of Regulatory Commissioners of the State of New Jersey, 44 F.3d 1178 (3rd Cir. 1995).

[308] See 18 C.F.R. § 292.301(c)(ii)(4) (2001).

[309] December 15 Order at 62,013.

[310] Id.

new ISO Governing Board was seated.[311] The ISO's bylaws were to become null and void as of January 29, 2001, to the extent they were inconsistent with this directive.[312] The Commission also stated that "if no consensus is reached regarding an acceptable means to select new ISO Board members [by April 29, 2001], then the procedures proposed in the November 1 Order will be carried out."[313]

The ISO, the Oversight Board, and the Western Power Trading Forum (WPTF) each filed a request for rehearing of the governance provisions of the December 15 Order. The ISO seeks rehearing and a stay of the requirement that the ISO Governing Board surrender authority to ISO management by January 29, 2001. The ISO argues that such a move could place a "cloud" over the ISO's corporate authority and, therefore, disrupt arrangements with lenders.

The Oversight Board argues that the December 15 Order should be revised to allow the State of California to restructure the ISO Governing Board subject to subsequent Commission review. The Oversight Board argues that because the ISO was expressly created by California law, California has the right to amend its restructuring law to change the governance structure of the ISO without prior Commission approval.

WPTF argues that it is inappropriate to allow California any significant role in the selection of a new ISO Governing Board. WPTF states that the ISO Governing Board must operate free from State influence in order to ensure that all market participants are treated fairly.

Commission Response

There are a number of pending proceedings that implicate the ISO's current governance structure and the extent of its independence. The context for approaching ISO governance has changed dramatically since issuance of the December 15 Order. The Commission finds it more appropriate to address governance issues in the context of these other, more recently filed proceedings. In addition, a Commission-initiated operational audit of the ISO is currently underway. Therefore, the arguments and concerns raised herein will be addressed in a future order.

5. Forward Contracting

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[311] Id. at 62,013-014.

[312] Id. at 62,014.

[313] Id.

A primary goal of the December 15 Order was to eliminate undue reliance on spot markets and thus the order took several measures to encourage longer-term contracting. Recognizing, inter alia, the expected shift of significant load from the spot to the forward market, the Commission adopted an advisory benchmark of $74/MWh for five-year contracts for supply around-the-clock and stated such contracts at or below that price "can be deemed prudent."[314] The Commission commented that this benchmark could be used as a reference point by buyers and sellers during negotiations, and that the Commission would consider that figure when addressing any complaints about prices in the long-term markets for contracts negotiated over the next year.[315] The order commented that the Commission was not establishing a new standard for market-based prices for long-term contracts and that buyers could reasonably elect to negotiate rates above that level for contracts containing terms and conditions which suited their particular needs.[316]

The order declined to mandate forward contracts at specified prices, however. Discussing a proposal by the California Commission to require medium-term forward contracts at regulated prices, modeled on "vesting contracts" used in New York, the order held that the idea would not be workable given the differences between the restructurings in New York and California.[317]

The California Commission and Reliant request rehearing of the determination that five-year contracts for supply around the clock at the benchmark can be deemed prudent. The California Commission argues that the decision is arbitrary and capricious, not based on substantial evidence, and not calculated properly, while Reliant asserts that the benchmark is unjust and unreasonable because it fails to take into account current market conditions and is not based on substantial evidence and objects that parties had no opportunity to comment on the idea.

The California Commission also requests rehearing on the basis that the Commission did not require that generators enter into medium-term forward contracts at regulated prices, alleging that the decision was arbitrary and capricious and not the product of reasoned decisionmaking. The California Commission asserts that such a

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[314] See 93 FERC at 61,994-95.

[315] Id. at 61,995 and 62,000.

[316] Id. at 61,995.

[317] Id. at 62,000.

requirement would not be unworkable and reiterates its argument that the Commission is required to impose cost-based rates when it finds that a market is dysfunctional.

Commission Response

The Commission presented the $74/MWh benchmark to assist buyers and sellers in their negotiations for longer-term contracts and has never relied on the figure in any proceeding. Since issuance of the December 15 Order, the Commission has never modified any rates or charges on the basis of the advisory benchmark. Further, no party has requested in a complaint that the Commission adjust a negotiated rate on the basis that it exceeds the benchmark. Thus, the California Commission and Reliant cannot allege that they were aggrieved by this aspect of the December 15 Order, and the Commission will dismiss these rehearing requests.[318] Should the issue be relevant in a future proceeding, the parties may raise their arguments concerning the development and level of the benchmark at that time.

As discussed elsewhere in this order, a return to cost-based rates in the California marketplace is not required by FPA section 206, and is not in the public interest. The California Commission's proposal to mandate forward contracts at regulated rates is not consistent with our approach throughout this proceeding and, in any event, is beyond the scope of this proceeding, which is limited to the spot markets. Accordingly, we will deny the rehearing request.

6. Issues of Procedure

On rehearing of the August 23 Order, PG&E and SoCal Edison request that the Commission clarify that refunds are appropriate where rates are found to be above just and reasonable levels. In addition, PG&E argues that the Commission should grant rehearing and immediately impose price caps pending the outcome of the investigation in the consolidated docket, and objects that the Commission did not address its request for interim, short-term mitigation measures. Finally, PG&E asserts that the Commission should begin hearing procedures immediately.

On rehearing of the November 1 Order, the California Commission argues that, until the Commission has the opportunity to review and respond to the comments filed

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[318]Section 313(a) of the Federal Power Act, 16 U.S.C. § 825l, permits only those persons that are aggrieved by a Commission order to request rehearing of that order. See, e.g., City of Summersville, 84 FERC ¶61,073 (1998) and Arizona Public Service Co., 26 FERC ¶61,357 (1984).

on November 22, 2000, the Commission is not able to determine whether disputes concerning material facts can be resolved without an evidentiary hearing. Specifically, the California Commission states that the Commission needs "further study of high-priced bidding by individual firms or periods when individual generators were not running."

The Cities of Santa Clara and Palo Alto, California (Cities) seek rehearing of the December 15 Order's directive that the ISO file revised congestion management procedures by January 31, 2001, arguing that the Commission in effect endorsed the proposed redesign under consideration as of December 15, 2000 because there would not be sufficient time to modify it before the January deadline.[319]

Commission Response

PG&E's and SoCal Edison's concerns have been addressed by subsequent orders. The Commission established paper hearing procedures in November 2000, and has applied the refund methodology to all transactions within the scope of the proceeding subsequent to the refund effective date. These measures protect the utilities' interests during the refund period. Accordingly, we will deny their rehearing requests.

We will reject the California Commission's argument. As the Commission explained in the November 1 Order,[320] we are not required to reach decisions on the basis of an oral, trial-type evidentiary hearing unless the material facts in dispute cannot be resolved on the basis of the written record.[321] The Commission's task in the November 1 and December 15 Orders was to fashion remedies to address dysfunctions in California's wholesale bulk power markets. While the Commission did require a factual understanding of the causes of the dysfunctions, this need was met by the parties' pleadings. Thus, a trial-type evidentiary hearing was unnecessary. The necessary determinations were made on the basis of a written record developed with paper hearing procedures.[322] Notably, the California Commission has not identified any specific factual dispute that the Commission could not resolve on the basis of the written record.

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[319]See December 15 Order at 62,017-18.

[320]November 1 Order at 61,373, n. 96.

[321]See, e.g., Duke Energy Moss Landing LLC and Duke Energy Oakland LLC, 86 FERC ¶ 61,187 at 61,657, n.7 (1999).

[322]Moreover, the July 25 Order set for hearing the remaining issues of fact required to be resolved so that the refund methodology could be implemented.

With respect to the Cities' argument, on January 30, 2001, the ISO filed a request for an extension of time to file its proposed congestion management redesign; as of this date, the ISO has not submitted a proposal and continues to allow further debate regarding redesigning its congestion management, thus satisfying Cities' concerns. We will, however, require the ISO to submit its proposal by May 1, 2002, in light of the necessity for adequate market structures to be in place when the price mitigation ends on September 30, 2002.

7. Other Related Dockets

a. ISO Amendment No. 33 (Docket Nos. ER01-607-000 and ER01-607-001)

The Commission accepted the ISO's Amendment No. 33 on December 8, 2000, the same day that the ISO filed its proposed tariff amendments.[323] Amendment No. 33 made three changes to the ISO Tariff. First, the existing $250/MWh purchase price cap on bids in the ISO's real-time Imbalance Energy Market was converted into a $250/MWh breakpoint. Second, generators that failed to comply with an ISO emergency dispatch order became subject to a penalty. Third, a Scheduling Coordinator with unscheduled demand or undelivered generation became liable for the cost the ISO incurred to obtain electricity through bids above the $250/MWh breakpoint or through out-of-market dispatches.

After issuance of the order, many entities filed motions to intervene (as listed in Appendix B) and requests for clarification, modification or rehearing objecting to the first two tariff revisions.

i. Due Process Issues

Interventions

Fourteen entities filed motions to intervene subsequent to the order's issuance and many of them sought rehearing. Several parties complain that the Commission violated due process by not affording the public any notice and opportunity to comment on Amendment No. 33.

Commission Response

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[323] See supra, n.5.

The Commission generally denies late interventions filed for the purpose of seeking rehearing.[324] Here, however, the Commission did not provide any notice of the ISO's filing before acting on it and, in fact, acted on the day of the filing. Thus, there was no opportunity for interested persons to seek to intervene or protest before the Commission took action. Also, all of the motions to intervene and requests for rehearing were filed within the 30-day deadline for filing rehearing requests under section 313(a) of the Federal Power Act, 16 U.S.C. § 825l(a) (1994), and Rule 713(b) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(b) (2001). Therefore, under these extraordinary circumstances, we find good cause to deviate from our usual practice and grant all of the motions to intervene filed in Docket Nos. ER01-607-000 and -001.

Due Process

Dynegy, Northern California Public Entities[325] and the California Commission argue that the Commission failed to provide due process when it accepted ISO Tariff Amendment No. 33 on the day that it was filed.

Commission Response

When the ISO filed Amendment No. 33, Stage 3 emergencies[326] had begun. The ISO stated in its filing that expedited implementation of Amendment No. 33 was needed to address a "severe and persistent bid insufficiency" in its real-time market, as well as failure by Participating Generators to respond to its emergency dispatch orders.[327] The situation was so grave that four days after the Commission accepted Amendment No. 33,

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[324]See, e.g., Southern Company Services, Inc., 92 FERC ¶ 61,167 at 61,565 (2000) (allowing intervention after issuance of an order in order to challenge that order, would result in unjustified delay and disruption of proceeding and undue burden on other parties); ISO New England, Inc., 94 FERC ¶ 61,237 at 61,845 n. 2 (2001) (denying intervention after issuance of order "consistent with Commission precedent"); see also The Power Company of America, L.P. v. FERC, 245 F.3d 839, 843 (D.C. Cir. 2001) (upholding FERC's denial of late intervention for failure to establish good cause for delay).

[325]These include TANC, Modesto, M-S-R Public Power Agency, and the Cities of Santa Clara and Redding.

[326]In a Stage 3 emergency, the ISO is authorized to curtail firm customers.

[327]Transmittal Letter for Amendment No. 33 at 2.

the Secretary of the Department of Energy, using rarely invoked emergency powers under section 202(c) of the Federal Power Act,[328] issued the first of several orders directing certain suppliers to provide electricity to California utility companies when the ISO certified that there was inadequate electrical supply.[329]

These circumstances demanded that we act immediately. Also, although the Commission did not provide specific notice of the ISO's filing of Amendment No. 33, the Commission had already provided notice in the November 1 Order that it was actively considering remedies of the sort included in that Amendment. In fact, the $250/MWh breakpoint provision of Amendment No. 33 was superseded days later by the $150/MWh breakpoint in the December 15 Order. Finally, by granting all requests for intervention in Docket No. ER01-607-000 and -001 and then considering all arguments raised on rehearing by intervenors, we have given all interested persons an opportunity to comment on Amendment No. 33. Therefore, we conclude that we have provided the due process necessary in the emergency circumstances presented.

Commission Determination Not to Consolidate

The Northern California Public Entities, noting the overlap between the issues addressed in the November 1 Order and the Amendment No. 33 Order, argue that the Commission acted improperly by docketing Amendment No. 33 in Docket No. ER01-607-000 rather than Docket Nos. EL00-95-000, et al., and contend that the Commission should consolidate the dockets.

Commission Response

Tariff amendments are properly filed pursuant to FPA section 205 (rather than FPA section 206, which is the vehicle for complaints such as the SDG&E proceeding). We accepted Amendment No. 33 to provide some immediate relief from a sudden emergency. In light of the urgency of that situation, we find that our decision to act through a separate docket was justified. Moreover, the administrative docketing of a filing does not determine the applicable procedures or substantive outcome and instead serves as a convenience in tracking proceedings. Nevertheless, we agree that it is appropriate to address the requests for rehearing of the Amendment No. 33 Order and the December 15 Order in a single order, which is what we are doing in this order. As we

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[328] 16 U.S.C. § 824a(c) (1994).

[329] DOE Order Pursuant to Section 202(c) of the Federal Power Act (Dec. 14, 2000).

are not setting any of the matters for hearing, however, there is no need to consolidate the dockets.

ii. Replacing the $250/MWh Purchase Cap with a $250/MWh Breakpoint

Adequacy of Breakpoint

The California Commission, PG&E, and SDG&E state that the Commission should not have allowed the ISO to remove the purchase cap and implement the $250/MWh breakpoint. PG&E argues that the $250/MWh breakpoint was too high; Dynegy argues that it was too low. Several parties state that the $250/MWh breakpoint in the ISO market had unintended consequences in the PX markets.

Commission Response

The $250/MWh breakpoint has been superseded by the July 25 refund methodology and prices for sales when Amendment No. 33 was in effect will be mitigated in accordance with that refund methodology. Thus, arguments about the breakpoint are moot. As discussed above, we conclude that the July 25 refund methodology will yield a just and reasonable outcome, and is a preferable, more market-oriented approach than a purchase cap. More importantly, the purchase cap was, by the ISO's unrefuted admission (confirmed by the Secretary's orders issued pursuant to FPA section 202(c)), impairing the ISO's ability to secure adequate supplies to ensure the reliability of operations within its control area. Our approval of the ISO's proposed breakpoint was a reasonable measure in ensuring continued service for the ISO's customers.

Implementation Issues

Parties raise concerns about reporting requirements and refunds for transactions that occurred while the $250/MWh breakpoint was in place. The ISO and PG&E seek clarification that generators who bid above $250/MWh must file cost information with the Commission, the ISO and the Oversight Board justifying their bids and making such bids subject to refund, as had been anticipated in the November 1 Order. Dynegy objects to submitting cost information to the ISO and the Oversight Board, arguing that the Commission is the only entity with jurisdiction to monitor justifications for wholesale market-based rates. The Northern California Public Entities seek clarification that any rates modified by Amendment No. 33 are still subject to any final determination the Commission makes regarding refunds in Docket Nos. EL00-95-000, et al.

Commission Response

Refund potential was established in the August 23 Order for sales that occurred during the period that Amendment No. 33 was in effect; although the Commission has moved away from the breakpoint approach and did not impose reporting requirements in the Amendment No. 33 Order, those transactions remain subject to refund. We clarify that final determinations regarding the refund methodology were made in the July 25 Order, as modified herein. With respect to requiring generators to submit cost justifications to the ISO and the Oversight Board, we note that the April 26 Order requires that cost justifications for bids above the mitigated reserve deficiency MCP be submitted to the ISO. In addition, parties have had access to generators' costs for the period between October 2, 2000 through June 20, 2001 pursuant to the Protective Order approved by the presiding judge in the refund hearing. We will not require direct submission of cost data to the Oversight Board because it has no authority to evaluate wholesale rates. We have previously determined that the Oversight Board's role is limited to matters within state jurisdiction.[330] The ISO, on the other hand, has a legitimate market monitoring function.

Effect on PX Markets

Several parties argue that Amendment No. 33 had unintended consequences in the PX markets. PG&E and SoCal Edison note that prices in the PX markets were restrained by the purchase cap in the ISO's real-time market, because buyers and sellers knew that if sellers demanded prices above the cap in the forward markets, buyers would hold out and obtain power at the capped price in the real-time market. Therefore, they argue that elimination of the purchase cap in the ISO market without the imposition of a breakpoint on sales in the PX markets left buyers more vulnerable to high prices. The PX, WPTF, Reliant, and Dynegy argue that despite the ISO's and the Commission's intent to encourage scheduling in forward markets, Amendment No. 33 actually created a disincentive for generators to bid into the PX forward markets. These parties note that

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[330] See California Power Exchange Corporation, et al., 85 FERC ¶ 61,263 at 62,067-69 (1998), reh'g denied, 86 FERC ¶ 61,114 (1999); Oversight Board, 88 FERC ¶ 61,172, at 61,576 (1999), reh'g denied, 89 FERC ¶ 61,134 (1999), dismissed sub nom. Western Power Trading Forum and Coalition of New Market Participants v. FERC, No. 99-1532 (D.C. Cir. filed April 10, 2001). We note that the Commission is considering the role of State Commissions in market monitoring in the context of the development of RTOs. See Notice of Extension of Time and Opportunity to Submit Comments on Regional Transmission Organization Issues Discussed at Workshops, Docket No. RM01-12-000, issued October 30, 2001.

prior to Amendment No. 33, a $250/MWh purchase cap was in place for all bids in ISO markets, not only bids in the real-time market, but also Adjustment Bids for protection of schedules during periods of congestion. Yet Amendment No. 33 only removed the purchase cap on real-time bids. Generators had been required to submit Adjustment Bids when they bid into the PX markets. The PX, WPTF, Reliant, and Dynegy argue that after Amendment No. 33, generators knew that in congestion situations they would be unable to protect their schedules at prices above the $250/MWh cap and, therefore, had an incentive to hold their bids until the real-time market, in which Adjustment Bids did not apply.

Commission Response

These concerns are now moot for several reasons. First, the December 15 Order applied the breakpoint to the PX spot markets, thus eliminating any disparity between PX and ISO markets. Second, the July 25 Order applied the refund methodology, based on the marginal costs of the least efficient unit dispatched, to PX spot market transactions for the period October 2, 2000 through January 31, 2001, when the PX ceased operations. In addition, the mechanism adopted by the ISO and PX to accommodate PX Adjustment Bids described in the ISO's compliance filing submitted in Docket No. EL00-95-008, et al., on January 2, 2001, resolved the adjustment bid issue.[331]

iii. Imposing Penalties For Noncompliance With ISO Emergency Dispatch Orders

Dynegy and others argue that it is unfair to impose penalties on generators who fail to respond to ISO emergency dispatch orders, arguing in part that generators should not be held responsible for NOx emission penalties incurred when responding to such dispatch orders.[332] Dynegy argues that the ISO has failed to offer adequate justification for assessing costs for undelivered generation. With regard to the assessment of costs for unscheduled load and undelivered generation, PG&E claims that assessing costs for underscheduled demand will give sellers unfair leverage.

Commission Response

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[331] The ISO's compliance filing is addressed in an order that is being issued concurrently with this order.

[332] Dynegy also raised this issue in its emergency motion for clarification on creditworthiness issues filed in Docket No. EL00-95-006.

The June 19 Order removed the penalty challenged by Dynegy for periods that price mitigation is in effect, as necessary in light of the must-offer requirement. The Commission agreed with generators that they should not be subjected to additional penalties for withholding generation for operational reasons. However, the Commission finds that the penalty was appropriately imposed prior to the imposition of the must-offer requirement and that it reasonably accepted the Tariff Amendment No. 33 in response to the immediate crisis facing California's markets in December 2000.

As an initial matter, we note that each Participating Generator entered into a Participating Generator Agreement through which it agreed to comply with the ISO's emergency dispatch orders, and each Scheduling Coordinator agreed to submit balanced schedules. Nevertheless, the ISO reported in its filing that "some Generators dispatched out-of-market [were] refusing to operate in response to the Dispatch instructions issued by the ISO, even during emergency conditions, unless special payment provisions [were] negotiated in real-time."[333] Compliance with emergency dispatch orders is critical to system reliability. The ISO's authority to issue such orders is limited to extreme situations involving imminent threats to reliability. When responding to such situations, the ISO should not be held hostage negotiating deals to entice Participating Generators into fulfilling their obligations. Imposition of a penalty for noncompliance with an emergency dispatch order was an appropriate mechanism for ensuring that the ISO would be able to deal effectively with threats to reliability.

We need not address Dynegy's argument that the rate the ISO Tariff sets for payment of power provided in response to such orders is confiscatory. We note that the issue of the rates paid for out-of-market calls will be addressed in Dynegy's complaint filed in Docket No. EL01-23-000, and we will not consider that issue here. We have addressed Dynegy's creditworthiness concerns in our March 6, 2001 order, in which we clarified that third-party suppliers are entitled to assurances of a creditworthy buyer for all energy delivered through the ISO, including energy supplied in response to an emergency dispatch order.[334]

We agree with Dynegy that a generator should not be held responsible for NOx emission penalties incurred as a result of complying with an ISO emergency dispatch order; prior orders have resolved this concern. The June 19 Order removed this penalty

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[333] ISO's Application in Docket No. ER01-607-000, at p. 2 .

[334] California Independent System Operator Corporation, et al., 95 FERC ¶ 61,024, reh'g denied, 95 FERC ¶ 61,391, further reh'g rejected, 96 FERC ¶ 61,267 (2001). See also California Independent System Operator Corporation, 97 FERC ¶ 61,151 (2001) (enforcing the earlier creditworthiness orders).

effective as of June 20, 2001, and pursuant to the July 25 Order, emissions costs will be offset against refund liability.

We disagree with Dynegy's argument that the penalty provision unfairly locked out of the market those generators who had intended to bid, but had not done so before the ISO issued the call. We conclude that the ISO needed the flexibility to issue dispatch orders before the deadline for regular submission of bids into the markets, so that the ISO could give Participating Generators as much advance notice as possible and have time to make adjustments for those Participating Generators who are unable to respond.

Finally, Dynegy argues that a penalty of twice the ISO's price of obtaining energy from an alternative source plus $1,000/MWh, if service is curtailed to consumers who are not covered by interruptible service policies, is disproportionate, citing our October 30, 1997 order conditionally approving operation of the ISO.[335] In that order, we noted that penalties charged by the ISO generally should be proportionate to the profits estimated to be earned by the abuse of market power. However, we also noted that "the penalty should also be greater than the estimated profits in order to serve as a deterrent to market power abuse."[336] Furthermore, in this case, the penalty was not in place simply to deter action that would result in unjust enrichment, but rather existed to protect the very reliability of the system. We conclude that the size of the penalty is appropriate for this purpose.

b. Docket Number EL00-97-001

On August 3, 2000, Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C. (Joint Complainants) jointly filed a complaint requesting that the Commission find that the ISO must compensate participating generators, Scheduling Coordinators, or other sellers (collectively, Market Participants) for their actual damages and lost opportunity costs in the event the ISO curtails energy exports scheduled by a Market Participant. In support of their complaint, Joint Complainants contended that the ISO Tariff does not specify how Market Participants are to be compensated if their energy exports are curtailed by the ISO in response to an ISO-declared system emergency. Joint Complainants stated that under standard arrangements for export transactions for firm delivery, Market Participants can be held liable to the would-be buyer for liquidated damages for failure to deliver. Joint Complainants also stated that in addition to liquidated damages, if export schedules are

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[335] See Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122 at 61,554 (1997).

[336] Id.

curtailed, Market Participants will lose the opportunity to sell the exported energy at competitive market prices. Therefore, Joint Complainants contended, if the ISO terminates an export transaction, the ISO should be made to hold the generator harmless from any damages that result from the ISO's decision and to provide the generator full recovery of its opportunity costs on the canceled export sale.

The December 15 Order rejected the complaint. The order found that, contrary to Joint Complainants' contention, the ISO Tariff does in fact contain a compensation mechanism for curtailed exports, i.e., the OOM payment mechanism codified in section 11.2.4.2 of the ISO Tariff.[337] The December 15 Order noted that the Tariff's current mechanism had been accepted by the Commission as part of Docket No. ER00-555-000 (ISO Tariff Amendment No. 23)[338] and, to the extent the complaint challenged the relevant Commission-approved Tariff provisions, the complaint was a collateral attack on that order.[339] In addition, the December 15 Order found that Morgan Stanley Capitol Group Inc., 92 FERC ¶ 61,112 (2000), which limited the ISO's authority to require sellers to bid into its markets, was not relevant to curtailments for the maintenance of system reliability, and Commission commented that the new pricing methodology would mitigate the adverse impacts of the ISO's reduced purchase price cap, lessening sellers' incentive to pursue exports.

Dynegy and Reliant[340] each object to the December 15 Order's rejection of the complaint. On rehearing, Dynegy and Reliant argue that the Commission wrongly concluded that sellers no longer would have incentives to pursue exports, that the Morgan Stanley case was not relevant, and that existing ISO Tariff provisions for OOM

[337]Under that mechanism, OOM payments are calculated by using either the hourly Ex Post Price or a price consisting of: (1) a capacity component based on certain market indices; (2) an energy component based on certain market indices; (3) verifiable start-up fuel costs; and (4) verifiable gas imbalances charges (if any).

[338]See California Independent System Operator Corp., 90 FERC ¶ 61,006 (2000), reh'g denied, 91 FERC ¶ 61,026 (2000), order on compliance filing, 90 FERC ¶ 61,165 (2000).

[339]December 15 Order, 93 FERC at 62,019-20.

[340]Enron also sought rehearing of the Commission's decision to reject the complaint in Docket No. EL00-97-000. We note, however, that Enron did not intervene in Docket No. EL00-97-000 and thus has no standing to seek rehearing of this aspect of the December 15 Order.

calls were adequate compensation for curtailed exports.[341] Dynegy explains that the complaint intended to request compensation along the lines of the "replacement price" adopted by NEPOOL and approved by the Commission.[342]

Commission Response

As an initial matter, the Commission did not mean to imply that, after removing the purchase price cap in the Amendment No. 33 and December 15 Orders, sellers would no longer have any incentives to pursue export transactions. Rather, the Commission was taking note that removal of the cap, the level of which triggered the Joint Complaint initially, resolved the adverse impacts complained about, both with respect to bidding incentives and the effect on the level of compensation.

With respect to the remaining matters raised on rehearing, we note that Joint Complainants offer no explanation why Morgan Stanley is relevant, and we have no reason to change our finding on that matter. Further, Joint Complainants have not demonstrated any changed circumstances that would warrant reconsideration of our December 15 Order. There, the Commission found that Joint Complainants were incorrect in asserting that the ISO Tariff provides no compensation for curtailed exports. On rehearing, Joint Complainants have failed to demonstrate that this was an incorrect conclusion. Rather, they continue to challenge the level of compensation that is available through the Tariff. The Commission explicitly rejected that argument in its December 15 Order, explaining that the argument was a collateral attack on a prior Commission order.[343] On rehearing, the only changed circumstances that Joint Complainants raise are events that could make curtailments more likely – they do not go to the level of compensation that may be appropriate.[344] Thus, we deny their request for rehearing.

In any event, the Commission understands that the ISO has never curtailed exports; thus, the alleged harm to Joint Complainants remains speculative.

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[341] See Requests for Rehearing of Dynegy at 12-18, and Reliant at 20-22.

[342] See Request for Rehearing of Dynegy at 17, citing New England Power Pool, 91 FERC ¶ 61,045 (2000) and New England Power Pool, 91 FERC ¶ 61,303 (2000).

[343] See December 15 Order, 93 FERC at 62,019-20.

[344] We note that the ISO's authority to require curtailment of imports is limited to reliability purposes, and it cannot be used to depress prices.

c. Complaints in Docket Nos. EL00-104-001, EL01-1-001, and EL01-2-001

Three additional complaints were filed with the Commission after SDG&E's complaint seeking relief related to the dysfunctional markets in California. First, the Oversight Board filed a complaint in Docket No. EL00-104-000 asking the Commission to find that the wholesale markets in California are not workably competitive and requesting that the Commission affirmatively direct the ISO to maintain bid caps at certain levels. Second, CMUA filed a complaint in Docket No. EL01-1-000 requesting that the Commission impose cost-based rates on public utility sellers into the ISO and PX markets. In support of its complaint, CMUA argued that California consumers were experiencing unprecedented high, sustained wholesale power prices. CMUA also argued that the California market was not workably competitive and that the framework to correct the problems was not in place. Third, CAlifornians for Renewable Energy, Inc. (CARE) petitioned the Commission to find that the wholesale markets in California are not workably competitive and make findings that the events and circumstances surrounding the June 14, 2000 rolling outage in the San Francisco Bay area warrant investigations by the United States Department of Justice of antitrust activities in restraint of trade and of alleged civil rights violations rendered by various entities.

The December 15 Order rejected the Oversight Board's and CMUA's complaints, noting that the modifications established in the order were intended to provide for uniform pricing and to remove incentives for load and resources to participate in one market over another, and that the relief sought would either disrupt that uniformity or introduce new incentives in the markets. CARE's complaint was denied on the basis that it had not provided adequate evidence in support of its allegation of an ISO/generator trust, nor did it document a single instance of restraint of trade or civil rights violations. The order also found that, in any event, the matter of whether the alleged violations warrant the initiation of an investigation by the Department of Justice was clearly not within the Commission's jurisdiction.

The California Commission and the Oversight Board argue on rehearing that the Commission erred in rejecting the latter's complaint on the grounds that no opportunity was given to conduct discovery, and reiterated the request for "hard" price caps. CMUA asserts that the Commission violated its statutory duty under the FPA by relying on the remedies in the December 15 Order, arguing that the Commission presented no empirical evidence for the proposition that those remedies are superior to the imposition of a cost-based rate. On rehearing, CARE largely reiterates its original allegations. CARE notes that it is a not-for-profit corporation relying on public funding and that it does not have the resources to obtain legal counsel to fully participate in the Commission's processes; thus, it requests assistance with its participation. In addition, CARE argues that it is the

Commission's responsibility to conduct a full and fair investigation of the matters in the proceeding and that its petition need not rise to the level of "substantial evidence." On March 23, 2001, CARE filed a request for Alternative Dispute Resolution services to resolve its complaint with the ISO, and specifying seven remedial actions not previously mentioned in its complaint. On August 30, 2001, CARE submitted a request for compensation for expenses associated with its participation in this proceeding. CARE invokes FPA section 319 (which authorizes certain assistance to the public),[345] contending that it does not have the resources to obtain legal counsel or other expert assistance.

Commission Response

As discussed elsewhere in this order, the remedies implemented in this proceeding have sufficiently mitigated the adverse market conditions in California. The Commission continues to believe that our market-oriented approach will enhance investment in new generation and promote greater efficiency. Moreover, the West-wide investigation and price mitigation measures instituted in Docket No. EL01-68-000 obviate the need to establish a regional cap in this proceeding.

Although we acknowledge CARE's concerns regarding lack of resources, we nonetheless will deny CARE's requests for rehearing and administrative aid. CARE's request for rehearing merely reiterates the allegations and evidence included in its initial complaint, and we reject it for the reasons stated in the December 15 Order. The discussion above relative to the Oversight Board and CMUA complaints also responds to CARE's request in its complaint and on rehearing that the Commission rectify the unjust and unreasonable prices stemming from the ISO and PX markets. CARE's rehearing does not address the fact that antitrust and civil rights violations are not within the Commission's jurisdiction or expertise. We will reject CARE's March 23 request for ADR procedures, because the motion, which outlines remedies not previously requested, constitutes a new complaint, and CARE has not followed the proper procedures for filing a new complaint.

Regarding CARE's request for administrative aid, on November 5, 2001, the Presiding Administrative Law Judge in Docket Nos. EL00-95-045 and EL00-98-042 issued a procedural order rejecting CARE's August 30, 2001 request for compensation. The Presiding Judge stressed that even if the pleading, which lacked the required certificate of service to other parties, had been properly filed, he would have denied the

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[345] 16 U.S.C. § 825q-1 (1994).

request on the merits. Subsequently, on November 13, 2001, CARE refiled its request for compensation directly with the Commission and included a certificate of service.

We will deny CARE's request for the following reasons. Initially, FPA section 319 was enacted by Congress as part of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[346] In section 212 of PURPA (later codified as FPA section 319), Congress created within the Commission an Office of Public Participation (OPP). Section 319 required the Director of the OPP to "coordinate assistance to the public with respect to authorities exercised by the Commission." As relevant here, Congress authorized funding for the OPP through fiscal year 1981. It did not authorize funding for OPP beyond that time and has not since appropriated any funds to the Commission to operate the OPP. Therefore, for lack of financial support, we deny CARE's request.

Further, even assuming that funding for the OPP still existed, because the nature of CARE's contribution to this proceeding, if any, cannot be determined at this time, the Commission denies CARE's request as premature.[347] Finally, even assuming the funds were available and CARE's request were not premature, the Commission denies the request on its merits because, as the Presiding Judge noted, "[t]he public interest [already] is represented by Commission Staff and state agencies and private interests are represented by interested parties who retain separate counsel." Granting CARE's request for administrative aid would be pointless, given the Commission's lack of jurisdiction over certain aspects of its complaint, and the abundant representation by other parties regarding the other matters raised by CARE.

d. Docket Nos. ER00-3461-001 and ER00-3673-001

In August 2000, the PX filed a tariff amendment proposing to impose maximum prices for bids in its Day-Ahead and Day-of markets of $350/MWh (Docket No. ER00-3461-000). Shortly thereafter, the ISO proposed to remove the existing November 15, 2000 termination date of its purchase price cap authority and to preserve its discretion to adjust the cap levels as appropriate (Docket No. ER00-3673-000). The November 1

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[346]Public Law No. 95-617 (1978).

[347]See Central Power and Light Company 8 FERC ¶ 61,065 at 61,220, order denying rehearing and modifying order, 9 FERC ¶ 61,011 (1979), reh'g denied, 10 FERC ¶ 61,131 (1980) (declining a similar request under Section 319 for attorney's fees, expert witness' fees, and other costs of intervening and participating before the Commission, explaining that "[u]nder the terms of that section, any such compensation must be made post-hearing and after a determination as to the nature of the intervenor's contribution to the proceeding."

Order rejected both of these proposals. With respect to the ISO's purchase price cap, the Commission found that the cap had served to mitigate price volatility in both the ISO and PX markets, but had also served to disrupt the market by encouraging sellers to wait for the ISO to make needed purchases on an out-of-market basis at the last minute.[348] Thus, the Commission decided not to allow either the ISO or the PX to implement changes that would disrupt the price mitigation measures proposed in that order. The Commission in the November 1 Order directed the ISO to retain its existing $250/MWh purchase price cap through the end of the year, until the proposed price mitigation measures would be implemented.

The California Commission and the Oversight Board sought rehearing, arguing that the Commission erred by removing such an important price control tool and that the Federal Power Act does not allow the Commission to "abandon customers to an unworkable marketplace."[349]

Commission Response

We will deny the rehearing requests of this aspect of the November 1 Order. The Commission has been and remains committed to establishing market-driven price mitigation measures, but the ISO and PX proposals would have disrupted efforts to move in that direction. Contrary to the assertions of the California Commission and the Oversight Board, customers were not left to the whim of "an unworkable marketplace." The November 1 Order made clear that refund potential was in place for the period October 2, 2000 forward, and transactions during the refund period were subject to the refund methodology adopted in the July 25 Order.

e. ISO Amendment No. 30 (Docket No. EL00-95-002)

On September 11, 2000, in response to a Commission directive given in the August 23 Order, the ISO filed Tariff Amendment No. 30. In that filing, the ISO proposed to amend section 2.5.3.1.5 of the ISO Tariff to clarify the ISO's authority to contract without first soliciting bids. The ISO indicated its belief that, while the current tariff provision did not specify that a competitive solicitation must be conducted for forward contracting, clarification of any ambiguity was appropriate. The ISO also proposed to amend one section of the ISO Tariff and to add another section for the purpose of allocating the costs of any forward contracts to those Scheduling Coordinators who are responsible for the incurrence of such costs (i.e., generation or

[348] November 1 Order at 61,371.

[349] California Commission at 22.

load that deviates, in real-time, from schedules) in proportion to their deviation. According to the ISO, fairness and providing appropriate economic incentives to Scheduling Coordinators to align their forward and real-time schedules, dictated the allocation. In addition, the ISO explained that to the extent that such allocation was not sufficient to make the ISO whole for the costs it incurs, any remaining balance would be incrementally flowed through the Tariff's neutrality clause (section 11.2.9) as charges incurred for the benefit of all market participants.

The December 15 Order accepted without modification the ISO's proposed Tariff Amendment. Regarding the intervenors' concerns that the ISO be limited in its use of forward contracting, the Commission stated that the remedies imposed therein, particularly those intended to significantly reduce underscheduling, would serve that purpose. Thus, the Commission found, to the extent that the ISO's need to procure energy for the real-time market would be significantly reduced, the ISO's need to procure energy through forward contracting would be lessened accordingly. In addition, with respect to the arguments opposing the ISO's proposed allocation methodology, the Commission found those arguments to be without merit, stating that the proposed methodology allocates costs in a manner consistent with other such methodologies the Commission has accepted in the past.

On rehearing, PPL contends that the Commission should have rejected ISO Tariff Amendment No. 30 for two reasons. First, PPL argues that the provisions allowing the ISO to charge any unrecovered balance to all Scheduling Coordinators is unjustified because it penalizes those entities who submitted accurate schedules. Second, PPL contends that under Tariff Amendment No. 30, the ISO became a market participant, thus jeopardizing its neutrality and independence contrary to the Commission's previous mandates (e.g., Order Nos. 888 and 2000).[350]

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[350]See Order No. 888, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Statutes and Regulations, Regulation Preambles January 1991-June 1996 ¶ 31,036 at 31,731 (1996) (stating "[a]n ISO should have the primary responsibility in ensuring short-term reliability of grid operations"), order on reh'g, Order No. 888-A, FERC Statutes and Regulations ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom., Transmission Access Policy Study Group, et al. v. FERC, 225 F.3d 667 (D.C. Cir. 2000).

In a similar vein, Modesto asserts that the Commission erred by failing to require the ISO to comply with the separation of function requirements of Order No. 889.[351] Modesto claims that the ISO is performing a wholesale merchant function and thus should conform with the Standards of Conduct rules in 18 C.F.R. § 37.4.

Commission Response

We will deny PPL's request for rehearing. In the context of the extraordinary circumstances before us in this proceeding, we believe that Tariff Amendment No. 30 constitutes a reasonably balanced effort to satisfy both the ISO's independence requirement under Order No. 888 as well as one of the Commission's primary goals in this proceeding of reducing the cost to Scheduling Coordinators of the ISO's real-time energy market. The ISO recognizes that it "should not be competing against Load-serving entities for the energy needed to satisfy Load that is reasonably predictable,"[352] and makes clear its intent to restrict its market activities to a minimum.

In addition, we find PPL's contention regarding Tariff Amendment No. 30's cost allocation methodology to be without merit. PPL's allegation merely reiterates arguments the Commission previously rejected in the December 15 Order, and we reject them now for the reasons stated therein.[353] As explained above, the allocation of costs to all Scheduling Coordinators applies only if the primary allocation methodology (i.e., to those Scheduling Coordinators who deviate, in real-time, from schedules, in proportion to their deviation) is not sufficient to make the ISO whole for the costs it incurs. In view of this fact, and in light of our precedent discussed above, PPL has not shown the allocation methodology to be an unreasonable means of ensuring that the ISO fully recovers its costs for maintaining system security.

Regarding Modesto's argument, the Commission agrees that the ISO must comply with the separation of function requirements described in 18 C.F.R. § 37.4. Given the ISO's limited usage of its forward contracting authority, however, we find no need at this

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[351] Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct, Order No. 889, 61 Fed. Reg. 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 Fed. Reg. 12,484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

[352] Transmittal Letter for Amendment No. 30 at 2.

[353] December 15 Order at 62,020.

time for any additional measures requiring the ISO to prove that it is in compliance with the Standards of Conduct, as Modesto requests.

f. Compliance Filings in Docket Nos. EL00-95-007, et al.

The ISO, the PX, and the three IOUs submitted compliance filings in late December and early January. The Commission acted on the PX's compliance filing in an order issued January 29, 2001.[354] The ISO's compliance filing is addressed in an order being issued concurrently with this order. The remainder of the compliance filings will be addressed herein.

PG&E, SDG&E, and SoCal Edison describe how they implemented the directive not to sell or buy through the PX markets. These actions did not require the companies to filed revised tariff sheets. PG&E and SoCal Edison included requests for clarification of the December 15 Order with their compliance filings. SoCal Edison requests that the Commission clarify that it may continue to sell into the PX output from its retained fossil generating resources because it may be unable to obtain cost recovery under state law if it does not bid those resources into PX markets. SoCal Edison also seeks clarification that it may sell its surplus output to any customer, including the PX. It explains that this clarification is necessary because the PX's markets are the only approved markets for SoCal Edison's market-based rate sales.

PG&E sought five areas of clarification: (1) whether the Commission intended to preclude even optional use of the PX's markets; (2) whether the Commission intends to review bids above the breakpoint despite lack of implementation by the ISO and/or PX; (3) how Ancillary Services above the breakpoint could be justified, given that the costs of providing such services are sunk unless units are dispatched; (4) whether reporting requirements for transactions above the breakpoint include bilateral contracts entered into by sellers in ISO and PX markets; and (5) how customers are to be provided an opportunity to review costs and justifications for above-breakpoint transactions. With respect to this last issue, PG&E requests that the Commission provide data on such bids to customers, and an opportunity to request cost support, evaluate the data, and contest the cost justification. NCPA and PPL filed answers to PG&E's request for clarification, objecting to the scope of data disclosure PG&E seeks. In addition, PPL comments on the proper scope of the reporting requirements.

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[354] San Diego Gas & Electric Co., et al., 94 FERC ¶ 61,085, reh'g denied, 95 FERC ¶ 61,021 (2001).

Notices of the filings were published in the Federal Register, 66 Fed. Reg. 2897 and 4813 (2001), with motions to intervene and protests due on or before January 23, 2001, for SDG&E's and PG&E's filings, and on or before February 1, 2001 for SoCal Edison's. No comments or protests were filed with respect to the companies' compliance with the December 15 Order; NCPA's and PPL's responses relate solely to PG&E's request for clarification.

Commission Response

We will accept for filing PG&E's, SoCal Edison's, and SDG&E's compliance filings. We will also address those requests for clarification that are not moot as a result of the cessation of the PX markets or have not previously been answered.

We clarify for SoCal Edison that it may sell its surplus output to customers other than the PX, but we will require it to file an amended market-based rate tariff to reflect this change.[355] PG&E's concerns about the treatment of Ancillary Services are addressed elsewhere in this order. Regarding participants' opportunity to review cost data, we note that sufficient data will be available to parties that have executed a non-disclosure agreement in the refund hearing before Administrative Law Judge Birchman.

D. Rehearing of Remaining Issues from March 9 Order

Numerous parties sought rehearing of the Commission's March 9 Order. Many of the arguments raised in those rehearings are identical to arguments raised on rehearing of the orders that are being addressed in this order. Furthermore, a number of the rehearings raise issues that have since been rendered moot by subsequent orders issued by the Commission. We will address below the rehearing issues that remain open for resolution.

1. Treble Damages

The California Commission argues that this Commission should order refund amounts comparable to the treble damages awarded in an antitrust case.

Commission Response

The Commission recently dealt with this very same argument in AES Southland, Inc., Williams Energy Marketing & Trading Co., 95 FERC ¶ 61,167 (2001). In that

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[355]We note that, for most hours, SoCal Edison is in a net short position so that it has little generation, if any, to sell.

order, the Commission explained that while it can order equitable remedies, such as disgorgement of unjust enrichment,[356] the Commission does not have authority to order treble damages as under the antitrust laws.[357]

2. Hearings

The ISO argues that, given the "dysfunctional" state of the California wholesale electricity market, it was arbitrary and capricious for the Commission to not have held trial-type evidentiary hearings to determine just and reasonable rates. Specifically, the ISO cites Cajun Electric Power Cooperative, Inc. v. FERC[358] for the premise that "it is an abuse of discretion for the Commission to refuse to hold a hearing when the petitioner has proffered facts that raise serious doubts concerning the mitigation of the utility's market power."

Commission Response

We will reject the ISO's argument. In general, the Commission must hold an evidentiary hearing "only when a genuine issue of material fact exists, and even then, FERC need not conduct such a hearing if [the disputed issues] may be adequately resolved on the written record."[359] Contrary to the ISO's argument, this is not a case like Cajun, where the record revealed a substantial factual dispute as to whether a Commission-approved tariff truly mitigated a utility's monopoly power,[360] and where the Commission "ignored this important question" and "failed to adequately explain its approval."[361] In this case, the Commission carefully considered the potential for market power by generators through its review of these generators' weekly transaction reports, as well as monthly reports from the ISO and the PX, and the system conditions that occurred in the ISO and PX markets. Furthermore, the Commission thoroughly

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[356] See generally Transcontinental Gas Pipe Line Corp. v. FERC, 998 F.2d 1313 (5th Cir. 1993) (and cases cited therein).

[357] See, e.g., Sunflower Electric Cooperative v. Kansas Power & Light Co., 603 F.2d 791 (10th Cir. 1979).

[358] 28 F.3d 173 (D.C. Cir. 1994) (Cajun).

[359] Id. at 177 (internal quotations and citations omitted).

[360] See id. at 175.

[361] Id. at 180.